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METHODS FOR ESTIMATING METHANE EMISSIONS FROM NATURAL GAS AND OIL SYSTEMS

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Prepared by:
ICF Consulting

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Peter Ciborowski, Environmental Protection Specialist, Minnesota Pollution Control Agency
Brenda Griffin, Program Analyst, Illinois Department of Natural Resources
Guido Franco, Program Analyst, California Energy Commission
William Herz, Assistant Research Engineer, University of Alabama, Department of Chemical Engineering
Patricia Kimes, Program Analyst, Utah Department of Environmental Quality
Don LaTourette, Program Analyst, New Hampshire Department of Environmental Services
Joe Loyer, Program Analyst, California Energy Commission
John Noller, Program Analyst, Missouri Department of Natural Resources
Sam Sadler, Energy Analyst, Oregon Department of Energy
Jack Sipple, Program Analyst, Delaware Department of Natural Resources and Environmental Control

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INTRODUCTION

The purposes of the preferred methods guidelines are to describe emissions estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. This chapter describes the procedures and recommended approaches for estimating methane emissions from oil and gas systems.

Section 2 of this chapter contains a general description of the oil and gas system source category. Section 3 provides a listing of the steps involved in using the preferred method for estimating greenhouse gas emissions from this source. Section 4 presents the preferred estimation method; Section 5 presents an alternative estimation technique. Quality assurance and quality control procedures are described in Section 6. References used in developing this chapter are identified in Section 7.

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SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

Oil and natural gas systems are the third largest source of methane in the U.S., comprising 18 percent of methane emissions and 1.7 percent of total GHG emissions in 1996 (U.S. EPA 1998). In the U.S., methane emissions from natural gas systems are about 5 times greater than methane emissions from oil systems.

This source category contains many distinct subcategories. It is important to account for emissions from oil and natural gas systems separately in order to differentiate between emissions associated with particular fuels. For purposes of this workbook, the terms natural gas or gas are used to refer to both natural gas (extracted from the ground), and "synthetic" or "substitute" natural gas (comprised mostly of methane) produced from other petroleum-based products or sources. Depending on its origin and how it is processed, commercially distributed natural gas also will include various amounts of non-methane hydrocarbons (*e.g.*, ethane, butane, propane, and pentane), carbon monoxide, carbon dioxide, and nitrogen. Oil is used to refer to both oil extracted directly from the ground and oil produced by various synthetic processes, such as recovery of oil from oil shale or tar sands.

Methane is emitted during oil and gas production, storage, transportation, and distribution. "Fugitive" sources of emissions within oil and gas systems include: releases during normal operations, such as emissions associated with venting and flaring during oil and gas production, chronic leaks or discharges from process vents; emissions during routine maintenance, such as pipeline repair; and emissions during system upsets and accidents.

Oil and Natural Gas System Overview:

1. **Oil and Gas Production:** Oil and gas are withdrawn from underground formations using on-shore and offshore wells. While most gas production is from gas wells, frequently gas is found in association with oil, and is withdrawn simultaneously from the same geologic formation, and then separated. Gathering lines are used to bring the crude oil and raw gas to one or more collection point(s) within a production field. Because methane is the major component of natural gas, leaks or venting from these systems result in methane emissions.

2. **Crude Oil Transportation and Refining:** The largest single contributor to methane emissions from the oil sector is venting from crude oil storage facilities that hold the oil before it is piped or trucked to refineries. The methane that is in solution vaporizes and is vented from the storage tanks directly to the atmosphere, unless it is captured by vapor

recovery units. Some emissions occur as crude is transferred in tankers and pipelines for shipment to refineries. Methane emissions from crude oil streams are strongly dependent on the original methane content of the crude oil and its preparation for transport.

Refineries process crude oil into a variety of hydrocarbon products such as gasoline and kerosene. Refineries account for only about 2 percent of the emissions from the oil sector. Refinery outputs, referred to as "refined products," generally contain negligible amounts of methane. Consequently, methane emissions are not estimated for transporting and distributing refined products.

3. **Natural Gas Processing, Transportation, and Distribution:** Natural gas is processed to remove water and recover heavier hydrocarbons, such as ethane, propane and butane, and prepare the dried gas for transporting to consumers. Most gas is transported through transmission and distribution pipelines. A small amount of gas is shipped by tanker as liquefied natural gas (LNG).

The following are the main processing, transportation, and distribution activities:

- Gas processing plants: Natural gas is usually processed in gas plants to remove and process the natural gas liquids and prepare the natural gas for pipeline transportation. During processing, natural gas is dried and a variety of processes may be used to remove most of the heavier hydrocarbons, or condensate, from the gas. Processed gas is then injected into the natural gas transmission system and the heavier hydrocarbons are marketed separately. Major methane emissions sources in the gas processing are compressor fugitives, compressor exhaust, vents, pneumatic devices, and blowdown.

- Transmission pipelines: Transmission pipelines are large diameter, high pressure lines that transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to local distribution companies, or large volume customers. A variety of facilities support the overall system, including metering stations, maintenance facilities, and compressor stations located along pipeline routes. Compressor stations, which maintain the pressure in the pipeline, generally include upstream scrubbers where the incoming gas is cleaned of particles and liquids before entering the compressors. Reciprocating engines and turbines are used to drive the compressors. Compressor stations normally use pipeline gas to fuel the compressor. They also use the gas to fuel electric power generators to meet the station's electricity requirements. Major methane emissions sources are chronic leaks, compressor fugitives, compressor exhaust, vents, and pneumatic devices.

- Local Distribution Companies: Distribution pipelines are extensive networks of generally small diameter, low pressure pipelines. Gas enters distribution networks from transmission systems at "city gate stations," where the pressure is reduced for distribution within cities or towns. Major methane emissions sources are chronic leaks, meters, regulators, and mishaps.

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OVERVIEW OF AVAILABLE METHODS FOR ESTIMATING EMISSIONS

Section 4 below presents two preferred methods for estimating methane emissions; one for natural gas systems, and the other for oil systems.

Section 5 below presents an alternative method for estimating methane emissions from natural gas systems. This method is less complex than the preferred method, and uses data that are more readily available, but it is also less accurate than the preferred method. Note that the alternative method for natural gas systems is the same as the preferred method for oil systems. (There is no alternative method for oil systems.)

The data required for the preferred method for natural gas systems include: (1) the number of wells and offshore platforms, (2) the number of miles of gathering pipeline, (3) the number of gas processing plants, (4) the number of miles of transmission pipeline, and (5) the total number of services (i.e., gas meters). The data required for the alternative method for natural gas systems are state-level data on gas production, gas

> Methods for developing greenhouse gas inventories are continuously evolving and improving. The methods presented in this volume represent the work of the EIIP Greenhouse Gas Committee in 1998 and early 1999. This volume takes into account the guidance and information available at the time on inventory methods, specifically, U.S. EPA's *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions* (U.S.EPA 1998a), volumes 1-3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 1997), and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1996* (U.S. EPA 1998b).
>
> There have been several recent developments in inventory methodologies, including:
>
> - Publication of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1997* (U.S. EPA 1999b) and completion of the draft inventory for 1990 – 1998. These documents will include methodological improvements for several sources and present the U.S. methodologies in a more transparent manner than in previous inventories;
> - Initiation of several new programs with industry, which provide new data and information that can be applied to current methods or applied to more accurate and reliable methods (so called "higher tier methods" by IPCC); and
> - The IPCC Greenhouse Gas Inventory Program's upcoming report on Good Practice in Inventory Management, which develops good practice guidance for the implementation of the 1996 IPCC Guidelines. The report will be published by the IPCC in May 2000.
>
> Note that the EIIP Greenhouse Gas Committee has not incorporated these developments into this version of the volume. Given the rapid pace of change in the area of greenhouse gas inventory methodologies, users of this document are encouraged to seek the most up-to-date information from EPA and the IPCC when developing inventories. EPA intends to provide periodic updates to the EIIP chapters to reflect important methodological developments. To determine whether an updated version of this chapter is available, please check the EIIP site at http://www.epa.gov/ttn/chief/eiip/techrep.htm#green.

consumption, and oil production.

The preferred method for natural gas systems is based on a set of activity levels for the activities from which methane is emitted, and a set of emission factors presented in a study by the Gas Research Institute and the U.S. Environmental Protection Agency. (GRI/EPA, 1996) The study was based on a large survey of emissions from the natural gas industry.

The GRI/EPA study developed emission factors for activities in four segments of the natural gas industry: production, processing, transmission (including storage), and distribution. Within each segment, industry facilities and operations were analyzed to identify sources of methane emissions—both fugitive emissions (leaks) and vented emissions. The study identified approximately 100 components of natural gas systems that are methane emission sources. For each component, the study developed an emission factor. To estimate emissions, one multiplies these emission factors by the activity level for each component—e.g., amount of gas produced, numbers of wells, miles of pipe of a given type and operating regime, or hours of operation of a given type of compressor.

The U.S. EPA uses the finely grained GRI/EPA data on emission factors and activity levels to develop the annual U.S. inventory of greenhouse gas emissions. This approach is also the "Tier 3" approach recommended by the IPCC (IPCC 1997). However, for purposes of state-level estimation of methane emissions from natural gas systems, EPA has developed simplified emission factors that aggregate the emissions from throughout natural gas systems and represent those emissions as being associated with certain aspects of natural gas systems. Section 4 uses these emission factors, which require the use of only a few key activity levels. Thus, for each activity level, this methodology presents an emission factor that represents emissions both from the specified activity and from several associated activities.[1] Note that this simplified approach estimates emissions using data only on the natural gas system infrastructure, and does not use data on natural gas production.[2] However, the emission factors for the natural gas system infrastructure components also account for the emissions from production. The simplified approach is relatively accurate; when used to estimate total U.S. emissions from the natural gas sectors, it yields an estimate within six percent of the estimate generated using the full EPA/GRI database. However, the simplified approach is less accurate when used to estimate emissions for a state that transmits large amounts of gas but does not produce much gas. For such a state, the simplified approach would overestimate the state's emissions, because it would allocate to the state some emissions from gas production in other states.

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[1] Those states that are interested in obtaining the entire GRI/EPA database on emission factors may obtain the published database (GRI/EPA, 1996); an updated version of the database is available from Paul Gunning, EPA's Climate Protection Division (202-564-9736). However, it would be quite difficult to compile the state-level activity data needed to use this complete set of emission factors.

[2] The purpose of this workbook is to present emission estimation techniques for GHG sources and sinks in a clear and unambiguous manner. To this end, the simplified method strikes a balance between rigor, data collection efforts, and applicability to specific states. However, we understand that data availability and emission factors may vary by state and we encourage states to tailor this method as needed.

EPA recently developed and adopted an improved methodology for calculating emissions from the oil industry.[3] This methodology uses emission factors and activity data at a level of detail comparable to the GRI/EPA study for the natural gas industry. Until this approach is modified to make it usable at the state level, the preferred method for estimating methane emissions from oil systems continues to be the "Tier 1" approach developed by the Intergovernmental Panel on Climate Change (IPCC 1997). This approach is simpler than the preferred method for natural gas systems, but is also less accurate. This method involves three relatively simple steps: (1) obtain the required state-level data on oil production, oil refined, oil tankered, and gas production; (2) multiply activity levels by the appropriate emission factors; and (3) sum across activity types to calculate total emissions. The method yields median estimates, but can also be used to develop low and high estimates, by using low and high emission factors.

As noted above, the alternative method for natural gas systems is analogous to the preferred method for oil systems.

[3] USEPA (U.S. Environmental Protection Agency). 1999a. Draft Report. *Estimates of Methane Emissions from the U.S. Oil Industry*. Office of Air and Radiation. EPA-68-W7-0069.

4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

This section presents two preferred methods, one for natural gas systems and one for oil systems.

4.1 PREFERRED METHOD FOR ESTIMATING EMISSIONS FROM NATURAL GAS SYSTEMS

This section presents a method for estimating methane emissions from natural gas systems, based on a set of activity levels for the activities from which methane is emitted.

Step (1) Obtain Activity Data

- *Required Data:* Data are required for four stages of the natural gas system, as described below.

  For estimating production emissions: The data required are (1) number of wells, broken down into the number of non-associated wells and the number of associated wells (non-associated wells produce only gas; associated wells produce both gas and oil); (2) the number of offshore platforms in the Gulf of Mexico (if applicable); (3) the number of offshore platforms in water bodies other than the Gulf of Mexico (if applicable); (4) the number of miles of gathering pipeline.

  Because of the different characteristics of wells in different parts of the country, the data required vary in different regions. In Appalachian states,[5] data are required only for the total number of wells.

  For estimating gas processing emissions: The data required are the number of gas processing plants.

  For estimating gas transmission emissions: The data required are (1) the number of miles of transmission pipeline; (2) the number of transmission stations and storage stations (or use a default based on pipeline length as discussed below); and (3) the number of LNG storage stations. The last data element may be omitted if data are not available, since the emissions from LNG storage stations are small.

[5] West Virginia, Pennsylvania, Kentucky, New York, Maryland, and Virginia.

For estimating gas distribution emissions: The data required are (1) the number of miles of cast iron main pipeline, (2) the number of miles of unprotected steel main pipeline, (3) the number of miles of protected steel main pipeline; (4) the number of miles of plastic main pipeline, (5) the total number of services (the industry name for customer connections), (6) the number of unprotected steel services (or use a default based on the total number of services as discussed below), and (7) number of protected steel services (or use a default based on the total number of services as discussed below).

- *Data Sources*: Most of the activity level data required to generate the emissions are available in three publications.

Data on the number of wells by state can generally be found in the *Natural Gas Annual* (e.g., EIA 1997a), the *Basic Petroleum Data Book* (e.g., API 1998), or *Gas Facts* (e.g., AGA 1993). The breakout for associated and non-associated wells may be obtained by consulting local producers and requesting a rough percentage estimate. As an alternative, data in the *Natural Gas Annual* on the proportion of annual gas production from associated wells versus non-associated wells can be used as a proxy for the proportion of each type of well. *Gas Facts* provides data on the number of miles of gathering pipeline.

Each June, the *Oil and Gas Journal* provides data on the number of gas processing plants by state.

Data on the number of miles of transmission pipeline by state are reported in *Gas Facts*. Data on the number of gas transmission stations and gas storage stations may be available from state sources. If these data are not available, the number of gas transmission and storage stations may be estimated by multiplying the state's mileage of transmission pipeline by 0.005975 (for transmission stations) and 0.001357 (for storage stations). The number of LNG storage stations may be available from state sources. As noted above, however, LNG storage stations are a small source of emissions, and may be disregarded if data are not available.

Gas Facts reports mileage of distribution pipeline by type (steel, plastic and "other"). If a state has more detailed data on mileage of each of the four types of pipeline shown in Table 3.4-1, those data may be used with emission factors in the table for each type of pipeline. The mileage of each type of pipeline may also be estimated based on the ratios shown in the footnotes to Table 3.4-1. Alternatively, Table 3.4-1 provides a single emission factor applicable to all distribution pipelines. *Gas Facts* also reports data on the number of services, and the breakdown between protected steel services and unprotected steel services. Alternatively, these data may be available from local gas distribution companies. If state-level data are not available for the number of protected and unprotected steel services, a state may estimate these numbers by multiplying the total number of services by 0.4656 (for protected steel services) and 0.1246 (for unprotected steel services). The balance of services are made of plastic or copper.

- *Units for Reporting Data*: The units for reporting data are either the number of a given type of unit (e.g., the number of a given type of well) or the number of miles of a given type of pipeline.

Step (2) Develop Estimate of Methane Emissions

The methane emissions estimation procedure is demonstrated in Table 3.4-1. It is important to understand that each emission factor accounts for emissions from several activities. For example, in calculating the production emissions for an Appalachian state, N (the number of wells) has an emission factor of 2.50 metric tons of CH_4 per well. This factor represents emissions not just from wells, but also from pneumatic devices, dehydrator vents,[6] Kimray pumps, gas engines, and well clean-ups. The product (N*2.50) is an approximation of the emissions from all of these sources.

TABLE 3.4-1 METHANE EMISSION FACTORS FOR THE NATURAL GAS INDUSTRY

A. Required Activity Data	B. Emission Factor (metric tons CH_4 per unit N from column A)	Annual Methane Emissions (metric tons) {this column is the product of columns A & B}
PRODUCTION EMISSIONS		
Appalachian States Only (as defined in the text)		
N, total number of wells	2.50	
East North Central States Only (Illinois, Indiana, Michigan, Ohio, and Wisconsin)		
N, total number of wells	1.37	
N_N, number of non-associated wells	1.48	
Rest of the U.S.		
N, total number of wells	1.51	
N_A, number of associated wells	0.02	
N_N, number of non-associated wells	2.54	
N_{pg}, number of off-shore platforms in the Gulf of Mexico	20.4	
N_p, number of off-shore platforms not including those in the Gulf of Mexico	8.26	
All States		
L_{gp}, miles of gathering pipeline	0.37	
Subtotal: Gas Production Methane Emissions, in metric tons (sum the appropriate values for wells and add the value for gathering pipeline)		

[6] Although glycol dehydrators may represent the single most important venting-related release, in the interest of keeping the method simple, emissions from glycol dehydrators are "rolled up" in the regional emission factors.

A. Required Activity Data	B. Emission Factor (metric tons CH_4 per unit N from column A)	Annual Methane Emissions (metric tons) {this column is the product of columns A & B}
GAS PROCESSING EMISSIONS (ALL STATES)		
P, number of gas processing plants	948	
Subtotal: Gas Processing Methane Emissions (metric tons):		
GAS TRANSMISSION EMISSIONS (ALL STATES)		
S_T, number of gas Transmission stations[3]	891	
S_S, number of gas storage stations[4]	914	
L, miles of transmission pipeline	0.68	
S_{LNG}, number of LNG storage stations	914	
Subtotal: Gas Transmission Methane Emissions (metric tons):		
GAS DISTRIBUTION EMISSIONS (ALL STATES)		
M_{CI}, miles of cast iron distribution pipeline[5]	4.63	
M_{US}, miles of unprotected steel distribution pipeline[6]	2.16	
M_{PS}, miles of protected steel distribution pipeline[7]	0.11	
M_{Pl}, miles of plastic distribution pipeline[8]	0.42	

[3] In the absence of more accurate data, S_T may be estimated by the following: L*0.0060, where L is the length of transmission pipeline in miles.
[4] In the absence of more accurate data, S_S may be estimated by the following: L*0.0014, where L is the length of transmission pipeline in miles.
[5] In the absence of more accurate data, M_{CI} may be estimated by the following: 0.066*M, where M is the length of distribution pipeline in miles.
[6] In the absence of more accurate data, M_{US} may be estimated by the following: 0.098*M, where M is the length of distribution pipeline in miles.
[7] In the absence of more accurate data, M_{PS} may be estimated by the following: 0.53*M, where M is the length of distribution pipeline in miles.
[8] In the absence of more accurate data, M_{Pl} may be estimated by the following: 0.30*M, where M is the length of distribution pipeline in miles.

A. Required Activity Data	B. Emission Factor (metric tons CH_4 per unit N from column A)	Annual Methane Emissions (metric tons) {this column is the product of columns A & B}
Alternative approach—Default for M: miles of distribution pipeline	0.70	
Sub-Subtotal: Pipeline Methane Emissions, in metric tons (either sum the products of the activity levels for each of the four types of pipeline, multiplied by the respective emission factors, or copy the product of the activity level for all distribution pipeline, multiplied by the default emission factor)		
H, total number of services	0.014	
H_{US}, number of unprotected steel services[9]	0.033	
H_{PS}, number of protected steel services[10]	0.0035	
Sub-Subtotal: Services Methane Emissions, in metric tons		
Subtotal: Distribution Methane Emissions, in metric tons (sum the two sub-subtotals)		
TOTAL METHANE EMISSIONS FROM THE GAS INDUSTRY, IN METRIC TONS (sum all subtotals):		

Step (3) Convert Units to Metric Tons of Carbon Equivalent

- Convert from units of metric tons to units of metric tons of carbon equivalent (MTCE). First multiply by 21 (the global warming potential of methane) and then by 12/44 (the ratio of the atomic weight of carbon to the molecular weight of CO_2), to obtain the amount of methane in units of MTCE.

4.2 PREFERRED METHOD FOR ESTIMATING EMISSIONS FROM OIL SYSTEMS

This method estimates methane emissions from oil systems, based on oil and gas production, oil transport by tanker, and oil refining.

Step (1) Obtain Activity Data

- *Required Data*. The information required to estimate emissions from this source is based on activity (*e.g.*, production) by the oil sector. Data required include the amount of oil produced, refined, transported, and stored at oil facilities.

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[9] In the absence of more accurate data, H_{US} may be estimated by the following: H*0.12, where H is the total number of services.

[10] In the absence of more accurate data, H_{PS} may be estimate by the following: H*0.47, where H is the total number of services.

- *Data Sources*: In-state agencies should be consulted first. State-level data on oil production and on oil refining capacity are available in the *Basic Petroleum Data Book* (e.g., API 1998). State-by-state data for natural gas production (needed for estimating methane emissions from venting and flaring during oil production) may be found in the *Basic Petroleum Data Book* (e.g., API 1998), *Natural Gas Annual* (e.g., EIA 1997a), or *Gas Facts* (e.g., AGA 1993).

- *Units for Reporting* Data: Data should be provided in units of million Btu (MMBtu). Since oil data are usually reported in barrels and gas data in thousand cubic feet (Mcf)[8], apply the conversion factors listed in Table 3.4-2 to convert to MMBtu.

Table 3.4-2. Conversion Factors to Million BTU (MMBTU)

Fuel Type	If Data are Reported in	Multiply by
Crude Oil	Barrels	5.800[a]
Natural Gas	Mcf	1.000[b]

[a] Energy Information Administration (EIA), (1997), *Annual Energy Review: 1996*, US Department of Energy, Washington, DC, July 1997, p. 354.
[b] The Btu content of gas varies between on average 950 and 1050 Btus per cf. For convenience, 1,000 Btus can be used.

Example A state producing 60 million barrels of oil would produce an energy equivalent of:

60,000,000 barrels x 5.800 MMBtu/barrel = 348,000,000 MMBtu

Step (2) Estimate Methane Emissions in Tons

Sources of Methane Emissions in Oil Systems: Emissions from oil systems can be categorized into emissions during: (1) normal operations, (2) routine maintenance, and (3) system upsets and accidents. In Table 3.4-3 these emission types are linked to the different stages in oil systems. Based on available information, the sources listed as "major" account for the majority of emissions from each segment. Typically the majority of the emissions are from normal operations. Because data are limited and there is considerable diversity among oil systems throughout the U.S., other potential sources are also listed which may, in some cases, be important contributors to emissions.

1. **Normal Operations:** Normal operations are the day-to-day operations of a facility. Emissions from normal operations can be divided into two main source categories: (1) venting and flaring, and (2) discharges from process vents, chronic leaks, etc.

[8] Occasionally the term Mscf, thousand *standard* cubic feet is reported. Also, the term decatherm (Dth or Dt) may be used. A therm is 100,000 Btus, and is the unit most often used by distribution companies. One Dth is 10 therms, or one MMBtu (one million Btu).

Venting and Flaring - Venting and flaring refers to the disposal of gas that cannot be contained or otherwise handled. Venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas and pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs.

Venting activities release methane because vented gas typically has a high methane content. If the excess gas is burned in flares, the emissions of methane will depend on efficiency of combustion. Generally, the combustion efficiency for flare sources is assumed to be between 95 and 100 percent.

Discharges from Process Vents, Chronic Leaks, etc. - Oil production and transportation facilities emit methane due to a wide variety of operating practices and factors, including:

- Emissions from pneumatic devices (gas-operated controls such as valves and actuators). These emissions depend on the size, type, and age of the devices, the frequency of their operation, and the quality of their maintenance.

- Leaks from system components. These emissions are unintentional and typically consist of continuous releases associated with leaks from the failure of a seal or the development of a flaw, crack, or hole in a component designed to contain or convey oil. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from cracks or from corrosion.

- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks. Vapors, including methane, are emitted from the vents as part of the normal operation of the facilities.

- Emissions from starting and stopping reciprocating engines and turbines.

- Emissions during drilling activities, *e.g.*, gas migration from reservoirs through wells.

Table 3.4-3. Emissions from Oil Systems

Segment	Major Emissions Sources	Other Potential Emission Sources
Oil Production Oil wells Gathering lines Treatment facilities	Venting Normal operations; fugitive emissions; deliberate releases from pneumatic devices and process vents.	Flaring, maintenance, system upsets and accidents.
Crude Oil Transportation and Refining Pipelines Tankers Storage tanks Refineries	Normal operations; fugitive emissions; deliberate releases from process vents at refineries, during loading and unloading of tankers and storage tanks.	Flaring, maintenance, system upsets and accidents.

Source: IPCC, 1997

2. **Routine Maintenance:** Routine maintenance includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing or repair. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

3. **System Upsets and Accidents:** System upsets are unplanned events in the system. The most common upset is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure.

   Release systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and reinjected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or send gases to flare systems where complete combustion may not be achieved.

   The frequency of system upsets varies with the facility design and the operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions. Emissions associated with accidents are also included in the category of upsets.

To develop median estimates of methane emissions:[9]

- Multiply activity data by the appropriate emission factor, as presented in Table 3.4-4. Do this for each activity type presented in Table 3.4-4.

  Activity Level (MMBTU) **x** Emission factor (median, lbs CH_4/MMBTU) = lbs CH_4 (median)

- Divide the number of lbs/ CH_4 obtained by 2,000 lbs/ton to obtain tons of CH_4 produced.

  lbs CH_4 (median, for each activity) ÷ 2,000 lbs/ton = tons CH_4 (median, for each activity)

[9] Data are also provided in Table 3.4-3 to permit development of low and high estimates of methane emissions, if desired.

Table 3.4-4. Methane Emission Factors for Oil Activities

Sector	Activity Data (MMBtu)	Emission Factor (lbs CH_4/MMBtu)		
		Low	**High**	**Median**
Oil Production				
Oil	Oil Production	0.0007	0.0116	0.0062
Oil & Gas: Venting and Flaring (portion attributable to oil production)	Oil & Gas Produced[a]	0.0035	0.0163	0.0099
Crude Oil Transportation and Refining				
Transportation	Oil Tankered	0.0017	0.0017	0.0017
Refining	Oil Refined	0.0002	0.0033	0.0017
Storage Tanks	Oil Refined	0.00005	0.0006	0.0003

a Emissions are based on total production of oil and gas.
Source: IPCC, 1997; the emission factors for the oil portion of oil and gas venting and flaring have been estimated as one-half of the IPCC emission factors for venting and flaring from oil and gas production combined.

Step (3) Estimate Total Methane Emissions from Oil Systems

- Sum across the five activity types (i) to obtain total methane emissions from oil and natural gas systems.

$$\sum_{i_1}^{i_7} \text{tons } CH_4 \text{ (median)} = \text{Total } CH_4 \text{ Emissions from Oil Systems (tons } CH_4\text{, median estimate)}$$

Example For each 1,000,000 million BTU (MMBTU) of oil produced in a state, estimated methane emissions from oil production facilities would be :

Median

1,000,000 (MMBTU) **x** 0.0062 (lbs CH_4/MMBTU) = 6,200 lbs CH_4

6,200 lbs CH_4 ÷ 2,000 (lbs/ton) = 3.1 tons CH_4

Perform similar calculations for the other four activities, and then sum across all activities.

- Convert from units of tons to units of metric tons of carbon equivalent (MTCE). First, multiply the weight of methane in tons by 0.9072 to obtain the weight of methane in metric tons. Then multiply by 21 (the global warming potential of methane) and by 12/44 (the ratio of the atomic weight of carbon to the molecular weight of CO_2) to obtain the amount of methane in units of MTCE.

The method presented uses emission factors multiplied by activity data that describe the oil system production level. While it is relatively easy to obtain the necessary activity data, note that the basis for developing the emission factors used in this method is weak. Because oil systems are comprised of a complex set of facilities, simple relationships between emissions and components of the systems are not easily defined. In addition, no single set of emission factors can apply to all conditions. Consequently, more detailed assessments would be required to more accurately reflect the diverse nature of the industry throughout the U.S.[10]

The emission factors presented were developed as part of the IPCC emission inventory guidelines for oil and gas systems (IPCC, 1997), which was based on a review of all available published estimates of methane emissions from the various sectors of the oil and gas industry. Although the objective in developing the emission factors was to include all emissions sources and types (described in the previous section), in some cases no published emissions estimates were found for categories of emissions believed to be negligible.

Using the available published emissions estimates, the implied emission factors from each study were developed by dividing the emissions estimates by appropriate measures of system size or capacity. Across the studies, the resulting implied emission factors per unit of energy varied widely. The estimates were grouped by region, and within each region a range of emission factors was selected for the IPCC emissions inventory guidelines. The emission factors used are the factors developed from studies of the U.S. system.

The emission factors can be considered to be no better than "order of magnitude" estimates. Actual emissions depend on site-specific characteristics including facility design, operation, and maintenance. While these characteristics were considered to various extents in the studies that formed the basis for the emission factor estimates, the variation in characteristics among systems throughout the U.S. implied the need for a range of emission factors (median, low, and high).

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[10] As noted above, in 1999 EPA developed a more detailed assessment of methane emissions from the oil industry. Once adapted to state conditions, this method will be able to reflect the diversity of emission sources in the oil industry within the US.

5

ALTERNATIVE METHOD FOR ESTIMATING EMISSIONS FROM NATURAL GAS SYSTEMS

This method estimates methane emissions from natural gas systems, based on oil and gas production, and gas consumption.

Step (1) Obtain Activity Data

- *Required Data*. The information required to estimate emissions from this source is based on activity (*e.g.*, production) by sector (oil or gas). Data required include: the amount of oil produced, refined, transported, and stored at oil facilities; and the amount of natural gas produced, processed, and distributed to consumers.

- *Data Sources*: In-state agencies should be consulted first. However, if it is difficult to obtain data from these sources, state-by-state data on natural gas systems may be found in *Natural Gas Annual* (e.g., EIA 1997a) and *Gas Facts* (e.g., AGA 1993). State-level data on oil production (needed for estimating emissions from venting and flaring in natural gas systems) may be found in the *Basic Petroleum Data Book* (e.g., API 1998).

- *Units for Reporting* Data: Data should be provided in units of million Btu (MMBtu). Since gas data are usually reported in thousand cubic feet (Mcf)[11] and oil data in barrels, apply the conversion factors listed in Table 3.5-1 to convert to MMBtu.

Table 3.5-1. Conversion Factors to Million BTU (MMBTU)

Fuel Type	If Data are Reported in	Multiply by
Crude Oil	Barrels	5.800[a]
Natural Gas	Mcf	1.000[b]

[a] Energy Information Administration (EIA), (1997), *Annual Energy Review: 1996*, US Department of Energy, Washington, DC, July 1997, p. 354.
[b] The Btu content of gas varies between on average 950 and 1050 Btus per cf. For convenience, 1,000 Btus can be used.

[11] Occasionally the term Mscf, thousand *standard* cubic feet is reported. Also, the term decatherm (Dth or Dt) may be used. A therm is 100,000 Btus, and is the unit most often used by distribution companies. One Dth is 10 therms, or one MMBtu (one million Btu).

Example	A state producing 100 million Mcf of gas would produce an energy equivalent of:
	100,000,000 Mcf x 1.000 MMBtu/Mcf = 100,000,000 MMBtu

Step (2) Estimate Methane Emissions in Tons

Sources of Methane Emissions in Natural Gas Systems: Emissions from gas systems can be categorized into emissions during: (1) normal operations, (2) routine maintenance, and (3) system upsets and accidents. In Table 3.5-2 these emission types are linked to the different stages in gas systems. Based on available information, the sources listed as "major" account for the majority of emissions from each segment. Typically the majority of the emissions are from normal operations. Because the data are limited and there is considerable diversity among gas systems throughout the U.S., other potential sources are also listed which may, in some cases, be important contributors to emissions.

1. **Normal Operations:** Normal operations are the day-to-day operations of a facility. Emissions from normal operations can be divided into two main source categories: (1) venting and flaring, and (2) discharges from process vents, chronic leaks, etc.

   <u>Venting and Flaring</u> - Venting and flaring refers to the disposal of gas that cannot be contained or otherwise handled. Venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas and pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs.

   Venting activities release methane because vented gas typically has a high methane content. If the excess gas is burned in flares, the emissions of methane will depend on efficiency of combustion. Generally, the combustion efficiency for flare sources is assumed to be between 95 and 100 percent.

   <u>Discharges from Process Vents, Chronic Leaks, etc.</u> - Gas production, processing, transportation, and distribution facilities emit methane due to a wide variety of operating practices and factors, including:

   - Emissions from pneumatic devices (gas-operated controls such as valves and actuators). These emissions depend on the size, type, and age of the devices, the frequency of their operation, and the quality of their maintenance.

   - Leaks from system components. These emissions are unintentional and typically consist of continuous releases associated with leaks from the failure of a seal or the development of a flaw, crack, or hole in a component designed to contain or convey oil or gas. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from cracks or from corrosion.

- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks. Vapors, including methane, are emitted from the vents as part of the normal operation of the facilities. However, such process vents are minor methane sources in most gas production facilities.

- Emissions from starting and stopping reciprocating engines and turbines.

- Emissions during drilling activities, *e.g.*, gas migration from reservoirs through wells.

Table 3.5-2. Emissions from Natural Gas Systems

Segment	Major Emissions Sources	Other Potential Emission Sources
Oil and Gas Production Oil and gas wells Gathering lines Treatment facilities	Venting Normal operations; fugitive emissions; deliberate releases from pneumatic devices and process vents.	Flaring, maintenance, system upsets and accidents.
Natural Gas Processing, Transportation, and Distribution Gas plants Underground storage reservoirs Transmission Pipelines Distribution pipelines	Normal operations; fugitive emissions; deliberate releases from pneumatic devices and process vents.	Flaring, maintenance, system upsets and accidents.

Source: IPCC, 1997

2. **Routine Maintenance:** Routine maintenance includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing or repair. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

3. **System Upsets and Accidents:** System upsets are unplanned events in the system. The most common upset is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure.

   Release systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and reinjected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and the operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions. Emissions associated with accidents are also included in the category of upsets. Occasionally, gas transmission and distribution pipelines are accidentally ruptured by construction equipment or other activities. These ruptures not only result in methane emissions, but they can be extremely hazardous as well.

To develop median estimates of methane emissions:[12]

- Multiply activity data by the appropriate emission factor, as presented in Table 3.5-3. Do this for each activity type presented in Table 3.5-3.

  Activity Level (MMBTU) **x** Emission factor (median, lbs CH_4/MMBTU) = lbs CH_4 (median)

- Divide the number of lbs/ CH_4 obtained by 2,000 lbs/ton to obtain tons of CH_4 produced.

  lbs CH_4 (median, for each activity) ÷ 2,000 lbs/ton = tons CH_4 (median, for each activity)

Table 3.5-3. Methane Emission Factors for Natural Gas Activities

Sector	**Activity Data (MMBtu)**	**Emission Factor (lbs CH_4/MMBtu)**		
		Low	**High**	**Median**
Gas Production				
Gas	Gas Production	0.1069	0.1952	0.1510
Oil & Gas: Venting and Flaring (portion attributable to gas production)	Oil & Gas Produced[a]	0.0035	0.0163	0.0099
Natural Gas Processing, Transport, and Distribution				
Gas Processing, Transmission, and Distribution	Gas Consumption	0.1324	0.2742	0.2033

[a] Emissions are based on total production of oil and gas.
Source: IPCC, 1997; the emission factors for the gas portion of oil and gas venting and flaring have been estimated as one-half of the IPCC emission factors for venting and flaring from oil and gas production combined.

[12] Data are also provided in Table 3.5-3 to permit development of low and high estimates of methane emissions, if desired.

Step (3) Estimate Total Methane Emissions from Natural Gas Systems

- Sum across the three activity types (i) to obtain total methane emissions from natural gas systems.

$$\sum_{i1}^{i7} \text{tons } CH_4 \text{ (median)} = \text{Total } CH_4 \text{ Emissions from Gas Systems (tons } CH_4\text{, median estimate)}$$

Example For each 1,000,000 million BTU (MMBTU) of natural gas produced in a state, estimated methane emissions from natural gas production facilities would be :

Median

1,000,000 (MMBTU) **x** 0.2040 (lbs CH_4/MMBTU) = 204,000 lbs CH_4

204,000 lbs CH_4 ÷ 2,000 (lbs/ton) = 102.0 tons CH_4

Perform similar calculations for the other six activities, and then sum across all activities.

- Convert from units of tons to units of metric tons of carbon equivalent (MTCE). First, multiply the weight of methane in tons by 0.9072 to obtain the weight of methane in metric tons. Then multiply by 21 (the global warming potential of methane) and by 12/44 (the ratio of the atomic weight of carbon to the molecular weight of CO_2) to obtain the amount of methane in units of MTCE.

The method presented uses emission factors multiplied by activity data that describe the gas system production level. While it is relatively easy to obtain the necessary activity data, note that the basis for developing the emission factors used in this method is weak. Because natural gas systems are comprised of a complex set of facilities, simple relationships between emissions and components of the systems are not easily defined. In addition, no single set of emission factors can apply to all conditions. Consequently, more detailed assessments would be required to more accurately reflect the diverse nature of the industry throughout the U.S.

The emission factors presented were developed as part of the IPCC emission inventory guidelines for oil and gas systems (IPCC, 1997), which was based on a review of all available published estimates of methane emissions from the various sectors of the gas industry. Although the objective in developing the emission factors was to include all emissions sources and types (described in the previous section), in some cases no published emissions estimates were found for categories of emissions believed to be negligible.

Using the available published emissions estimates, the implied emission factors from each study were developed by dividing the emissions estimates by appropriate measures of system size or capacity. Across the studies, the resulting implied emission factors per unit of energy varied widely. The estimates were grouped by region, and within each region a range of emission factors was selected for the IPCC emissions inventory guidelines. The emission factors used are the factors developed from studies of the U.S. system.

The emission factors can be considered to be no better than "order of magnitude" estimates. Actual emissions depend on site-specific characteristics including facility design, operation, and maintenance. While these characteristics were considered to various extents in the studies that formed the basis for the emission factor estimates, the variation in characteristics among systems throughout the U.S. implied the need for a range of emission factors (median, low, and high).

6

QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance (QA) and quality control (QC) are essential elements in producing high quality emission estimates and should be included in all methods to estimate emissions. QA/QC of emissions estimates are accomplished through a set of procedures that ensure the quality and reliability of data collection and processing. These procedures include the use of appropriate emission estimation methods, reasonable assumptions, data reliability checks, and accuracy/logic checks of calculations. Volume VI of this series, *Quality Assurance Procedures*, describes methods and tools for performing these procedures.

The ability to estimate emissions from oil and gas systems will be hampered by the general lack of data on the factors that lead to emissions. These systems are very diverse and variable. Emissions cannot be accurately estimated with simple assumptions or rules of thumb. Nevertheless, recent studies indicate that the main types of emissions can be assessed with fairly straightforward approaches.

The most difficult emissions to estimate will likely be fugitive emissions from distribution systems. The precision of gas accounting data is typically not adequate to estimate emissions from these sources. Because these emissions can be quite important, specially conducted measurement studies using specially designed and operated meters and instruments may be required. Such studies would improve considerably the basis for estimating emissions from this source.

Carbon dioxide emissions from fuel used in compressor stations and related equipment for providing the pressure to transport the fuel over land are not counted in the methodologies in this chapter. These emissions should be counted as part of fossil fuel combustion emissions (Chapter 1 of this volume). The recommended data source for Chapter 1—the *State Energy Data Report*—does count carbon dioxide emissions from compressor stations and related equipment.

In addition, carbon dioxide emissions from certain gas and oil fields could be significant. However, the extent of these emissions has not yet been characterized; additional research would be required to understand and estimate these emissions.

6.1 DATA ATTRIBUTE RANKING SYSTEM (DARS) SCORES

DARS is a system for evaluating the quality of data used in an emission inventory. To develop a DARS score, one must evaluate the reliability of eight components of the emissions estimate. Four of the components are related to the activity level (e.g., the amount of oil or gas produced). The other four components are related to the emission factor (e.g., the amount of methane released per unit of oil or gas produced). For both the activity level and the emission factor, the four attributes evaluated are the measurement method, source specificity, spatial congruity, and temporal congruity. Each component is scored on a scale of zero to one, where one represents a high level of reliability. To derive the DARS score for a given estimation method, the activity level score is multiplied by the emission factor score for each of the four attributes, and the resulting products are averaged. The highest possible DARS composite score is one. A complete discussion of DARS may be found in Chapter 4 of Volume VI, *Quality Assurance Procedures*.

The DARS scores provided here are based on the use of the emission factors provided in this chapter, and activity data from the national-level data sources referenced in the various steps of the methodology. If a state uses state data sources for activity data, the state may wish to develop a DARS score based on the use of state data.

TABLE 3.6-1

DARS SCORES: CH_4 EMISSIONS FROM NATURAL GAS SYSTEMS, PREFERRED APPROACH

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	**7**	The factors were based on measurement of emissions from a small sample of sources over typical loads.	9	Data on each activity are based on intermittent measurement.	0.63
Source Specificity	10	An emission factor was developed for each of approximately 100 components of natural gas systems which were identified as methane emission sources.	9	The activities measured were identified as methane emission sources and thus are highly correlated to emissions.	0.90
Spatial Congruity	8	The factors were developed for the entire U.S., not for any state. Assuming variability within the U.S. is low to moderate, the score is 8.	9	Activity data are sometimes scaled based on national ratios of one activity to another; spatial variability is expected to be low.	0.72
Temporal Congruity	8	The emission factors are based on measured emissions over a period of less than a year. However, temporal variability is expected to be low, so the score is 8.	10	States use activity data from a given year to estimate emissions in that year.	0.80
				Composite Score	**0.76**

TABLE 3.6-2

DARS SCORES: CH_4 EMISSIONS FROM OIL SYSTEMS, PREFERRED APPROACH

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	2	Because emissions are not measured, the highest possible score is 5. Because of the wide range for each emission factor, we assigned a score of 2.	10	Data on each activity are based on continuous measurement.	0.20
Source Specificity	7	An emission factor was developed for each activity (e.g., production, refining, and distribution), but the emission factor aggregates emissions at a higher level than where they occur.	7	The activities measured (production, transportation, refining, and consumption) are highly correlated to emissions, but are aggregated at a higher level than where emissions occur.	0.49
Spatial Congruity	8	The factors were developed for the entire U.S., not for any state. Variability within the U.S. is assumed to be low to moderate.	5	States use state-level activity data to estimate statewide emissions, but these data (e.g., oil refined) are poor proxies for the desired activity level (e.g., oil stored).	0.40
Temporal Congruity	9	The emission factors are not based on measured emissions over a particular time frame. However, the emission factors should not vary significantly over the course of a year, so the score is 9.	10	States use annual activity data to estimate annual emissions.	0.90
				Composite Score	**0.50**

TABLE 3.6-3

DARS SCORES: CH_4 EMISSIONS FROM NATURAL GAS SYSTEMS, ALTERNATIVE APPROACH

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	2	Because emissions are not measured, the highest possible score is 5. Because of the wide range for each emission factor, we assigned a score of 2.	10	Data on each activity are based on continuous measurement.	0.20
Source Specificity	7	An emission factor was developed for each activity, but the emission factor aggregates emissions at a higher level than where they occur.	7	The activities measured (production, transportation, refining, and consumption) are highly correlated to emissions, but are aggregated at a higher level than where emissions occur.	0.49
Spatial Congruity	8	The factors were developed for the entire U.S., not for any state. Variability within the U.S. is assumed to be low to moderate.	5	States use state-level activity data to estimate statewide emissions, but these data (e.g., gas consumed) are poor proxies for the desired activity level (e.g., gas transiting a state).	0.40
Temporal Congruity	9	The emission factors are not based on measured emissions over a particular time frame. However, the emission factors should not vary significantly over the course of a year, so the score is 9.	10	States use annual activity data to estimate annual emissions.	0.90
				Composite Score	**0.50**

7

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